ATHABASCA OIL CORPORATION

FOCUSED | EXECUTING | DELIVERING

MARCH 4, 2026 – 2025 YEAR-END RESULTS

ATHABASCA
OIL CORPORATION

OUR VISION & STRATEGY

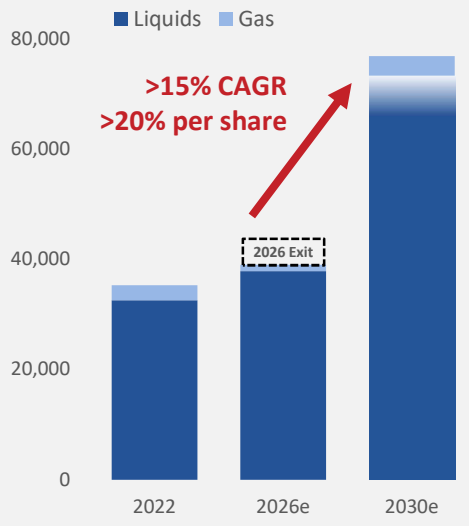
Low-Decline High-Quality Thermal Assets with 90 Year Reserve Life

Self-Funded Growth in High-Quality Kaybob Duvernay Oil Play

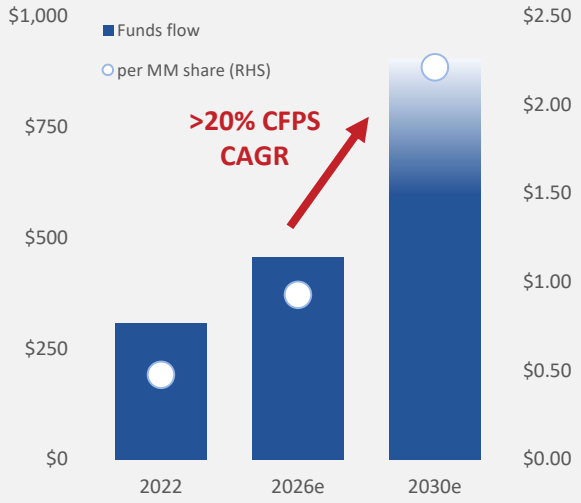
Pristine Balance Sheet with a Net Cash Position

DRIVING VALUE THROUGH PER SHARE GROWTH

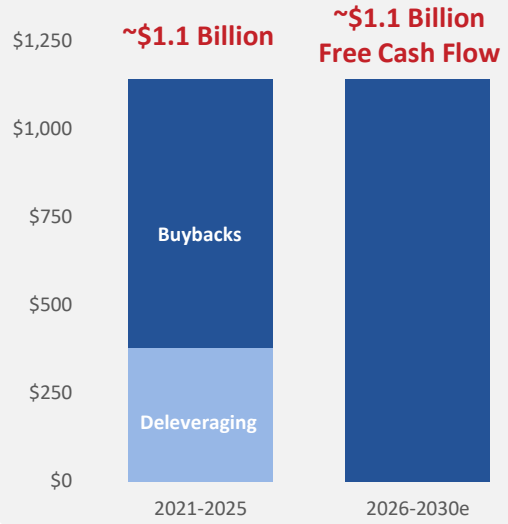
LIQUIDS GROWTH (BOE/D)



CFPS GROWTH ($MM; $/SH)



SHAREHOLDER RETURNS ($MM)



2026+ pricing: US$65 WTI, US$12.50 WCS diff, C$3 AECO, 0.725 C$/US$ FX.
Compound Annual Growth Rate "CAGR". See reader advisory "Oil and Gas Information" and "Non-GAAP and other Financial Measures and Production Disclosure" for more information.

CORPORATE SNAPSHOT

~40,000 BOE/D / 98% LIQUIDS / LOW BASE DECLINE

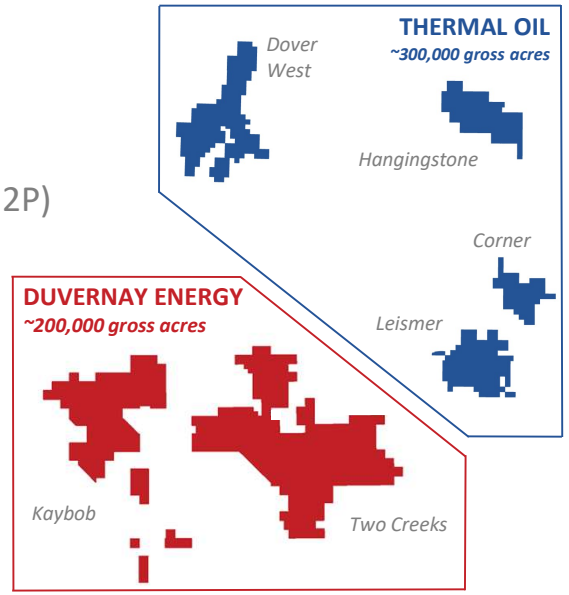
THERMAL OIL

- Predictable, low decline projects
- Compelling SAGD growth
- Unparalleled reserve scale (1.2 billion bbl 2P)

DUVERNAY ENERGY CORP. ("DEC")

- Pure play Duvernay subsidiary
- Self-funded & flexible development
- De-risked resource and high margins

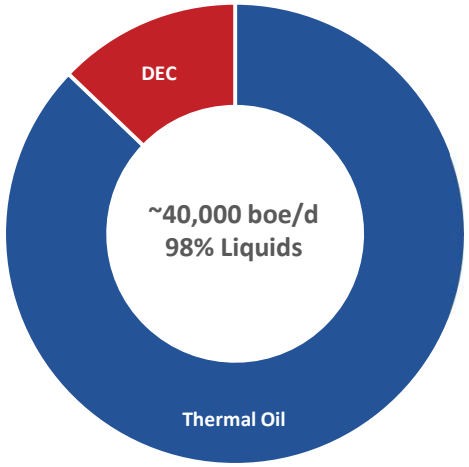
ATHABASCA ASSETS



CAPITALIZATION (Q4 CONSOLIDATED)

Basic Shares (ATH-TSX)	481MM
Market Cap. ($9/sh)	**~$4,300MM**
Daily Trading Liquidity	~$35MM
Net Cash	**$59MM**
Cash / Liquidity	$316MM $443MM
Tax Pools	$2.1B

PRODUCTION BY ASSET



2026 GUIDANCE (US$65 WTI)

	Thermal Oil	DEC (100%)	Consolidated
Production (boe/d)	32,000 – 34,000 *inclusive of ~2,500 turnaround impact*	~5,000	**37,000 – 39,000 Exit ~43,000**
Adj. Funds Flow ($MM)			**~$425 – $450**
Capital ($MM)	$273	$38	**~$310**

Basic shares & capitalization as at December 31, 2025. *DEC capital funded independently through its funds flow and its independent balance sheet.
2026 production: 90% Bitumen, 2% natural gas (comprised of 99%+ of shale gas), 7% Condensate NGLs, 1% Other NGLs.
See reader advisory "Additional Oil and Gas Information" and "Non-GAAP Financial Information" for more information.

2025 YEAR-END RESULTS

Production
39,375 boe/d (98% Liquids)
High end of guidance of 37,500 – 39,500 boe/d

Cash Flow
$504MM Adjusted Funds Flow
$1.01/sh FFO

Netbacks
$40/bbl Thermal Op. Netback
$35/boe Duvernay Op. Netback

Capital
$248MM AOC (Thermal Oil)
$75MM DEC
Within 2025 budget ~$325MM

100% Return of Capital
$230MM share buybacks
~24% reduction in share count since Q1 2023

Pristine Balance Sheet
$59MM Net Cash
$443MM Liquidity
Strategic Flexibility

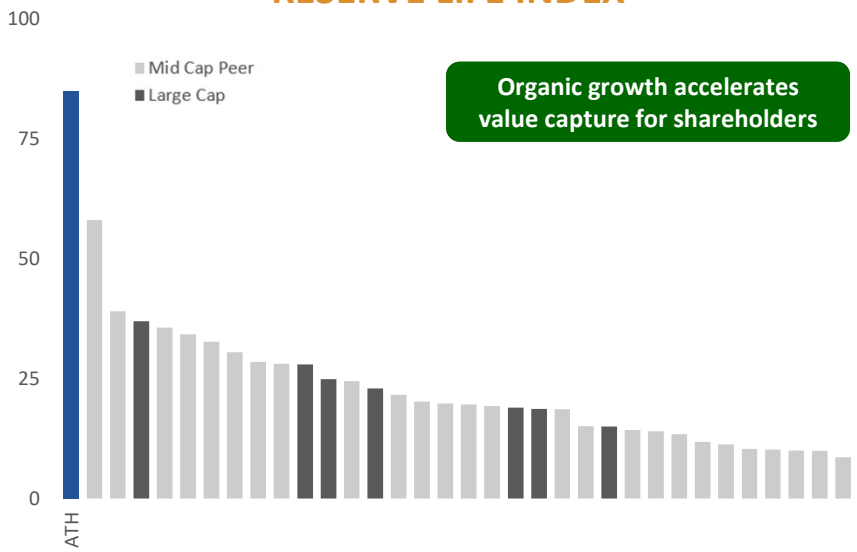
All numbers represent consolidated corporate results. 2025 production volumes by product: 35,905 bbl/d Bitumen, 4,947 mcf/d natural gas (>99% shale gas), 311 bbl/d other NGLs, 2,335 bbl/d Oil (>99% tight oil). Liquidity & Cash as at December 31, 2025. Net Cash = face value of long-term debt less working capital surplus (excl. risk management & warrant liability). See reader advisory "Additional Oil and Gas Information", "Reserve Information" and "Non-GAAP Financial Information" for more information. Share count reduction calculated using fully diluted shares outstanding.

DIFFERENTIATED LONG-LIFE RESERVES

2025 RESERVE & RESOURCE OVERVIEW

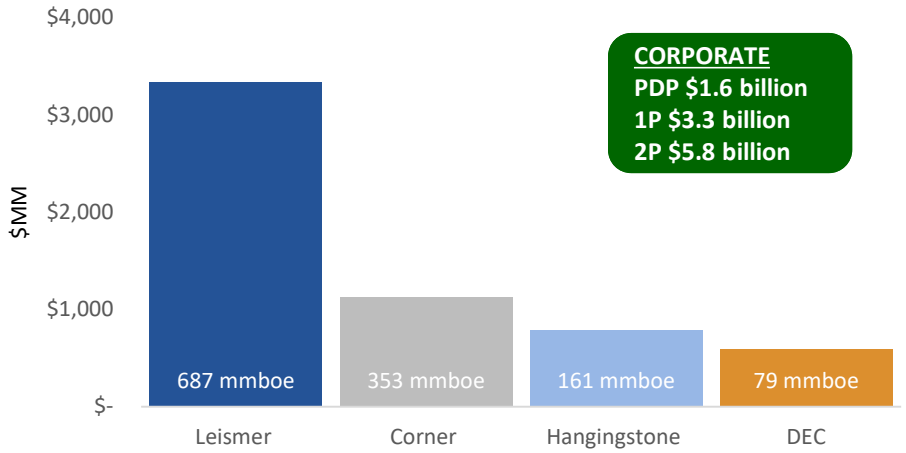
- Deep resource inventory
  - ~1.3 billion boe 2P reserves; ~85 year reserve life
  - ~1 billion bbl contingent resource
- Significant intrinsic value
  - $3.3 billion 1P NPV10
  - $5.8 billion 2P NPV10
- Compelling Thermal Oil project reserve metrics
  - ~$6/bbl lease-edge finding costs on sustaining pads
- Duvernay Value Capture
  - 79 mmboe 2P (up 9% Y/Y)
  - Significant running room with ~40% of 432 gross estimated Duvernay locations booked

RESERVE LIFE INDEX*



Source: Peters & Co. Research – 2024 Reserves Comparative – Canadian and U.S. Producers (April 3, 2025)
*Uses 2024 RLI's for peers, calculated using Q4/24 production

2P RESERVE VALUE (NPV10) & 2P RESERVES



Consolidated reserves as of December 31, 2025. Calculation for RLI is 2025 year-end reserves divided by Q4 2025 production.
Proved Developed Producing "PDP", Total Proved "1P", Proved plus Probable "2P".
See reader advisory "Additional Oil and Gas Information". "Reserve Information" and "Non-GAAP Financial Information" for more information.

ROBUST FREE CASH FLOW PROFILE

BUSINESS OUTLOOK

- Growth in Thermal Oil to >60,000 bbl/d by 2030
- Self-funded Duvernay Energy enhances growth

COMPETITIVE THERMAL PROJECTS

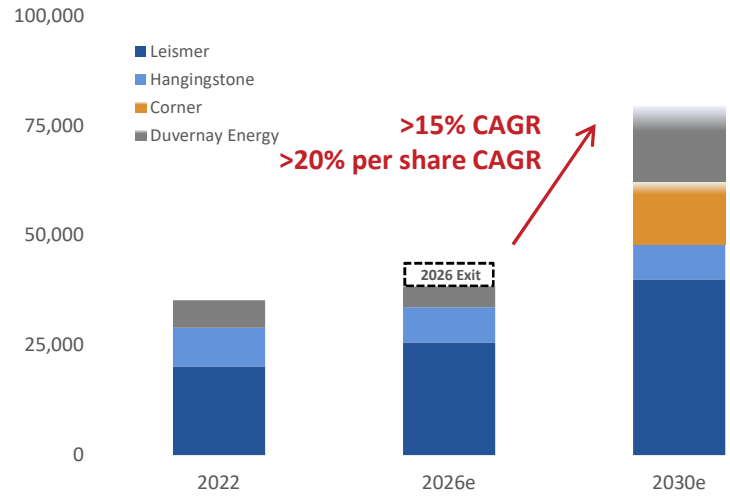
- Leismer growth underway (~$25,000/bbl/d cap. efficiency)
- Corner modular growth with sanction plans in 2026
- Thermal growth capital break-even ~US$55 WTI (incl. Corner)
  - Sustaining capital break-even ~US$45 WTI
  - Operating capital break-even ~US$40 WTI

100% FREE CASH FLOW TO SHAREHOLDERS

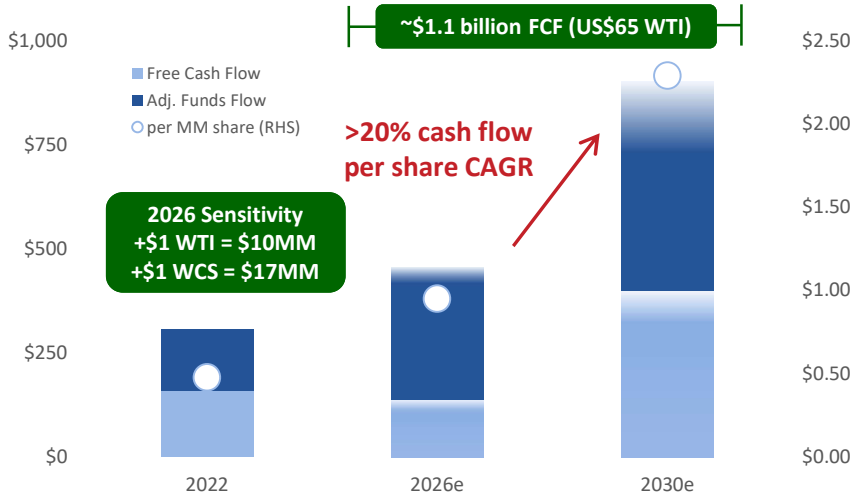
- ~$1.1 billion in shareholder returns since 2021
  - ~$720MM share buybacks since 2023
- ~$1.1 billion Free Cash Flow (2026-30e) at US$65 WTI

>20% cash flow per share CAGR over 5 years

CONSOLIDATED PRODUCTION (BOE/D)[1]



CONSOLIDATED ADJUSTED FUNDS FLOW ($MM, $/SH) [1]



Note: per share metrics assume 100% of Free Cash Flow is directed to share buybacks up to a 10% Normal Course Issuer Bid limit at an implied share price of 6x Enterprise Value/Debt Adjusted Cash Flow in 2027+

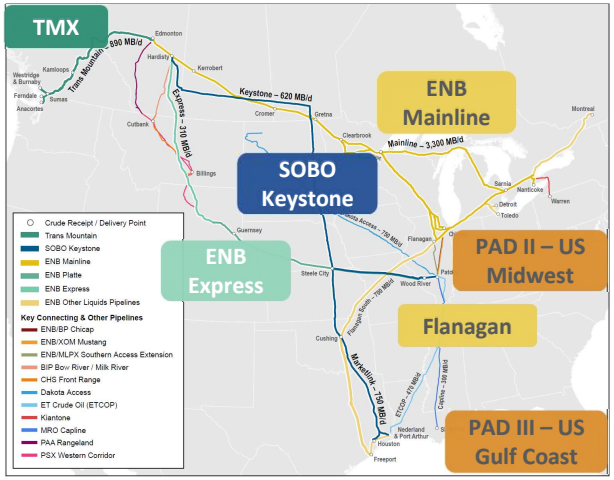
[1]Assumes AOC 100% Thermal Oil and DEC 70%. 2022 production includes Placid Montney which was disposed in September 2023. 2026+ pricing: US$65 WTI, US$12.50 WCS diff, C$3 AECO, 0.725 C$/US$ FX. Illustrative sensitivity reflects full year funds flow impact for changes in each variable. Compound Annual Growth Rate "CAGR". See reader advisory "Oil and Gas Information" and "Non-GAAP and other Financial Measures and Production Disclosure" for more information.

SECURED MARKET ACCESS

ATHABASCA INITIATIVES

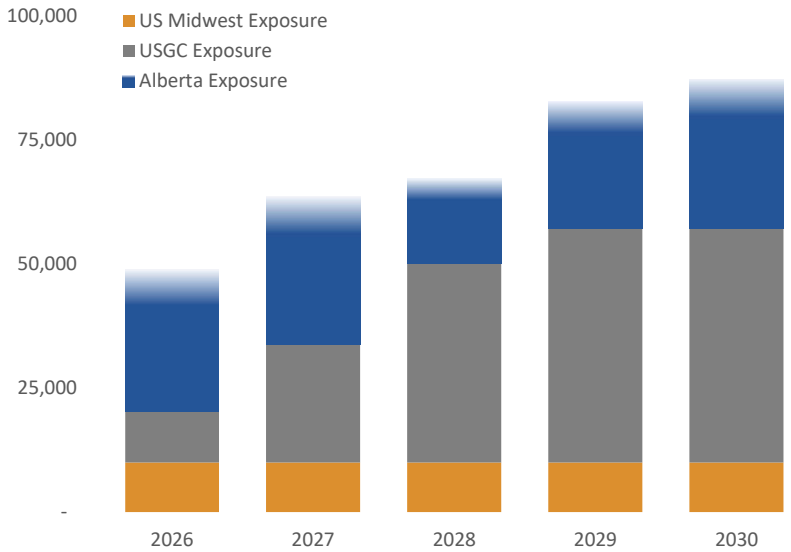
- Diversified market access for its development plans
  - Long-term egress aligned to growth initiatives and long-life assets
  - Provides protection against local market differential volatility
  - No balance sheet encumbrances
- Diversified contracted market access (~57,000 bbl/d blended capacity)
  - 47,000 bbl/d long-term capacity with exposure to the US Gulf Coast (PADD III)
  - 10,000 bbl/d of capacity providing exposure to the US Midwest (PADD II)

LIQUIDS PIPELINES



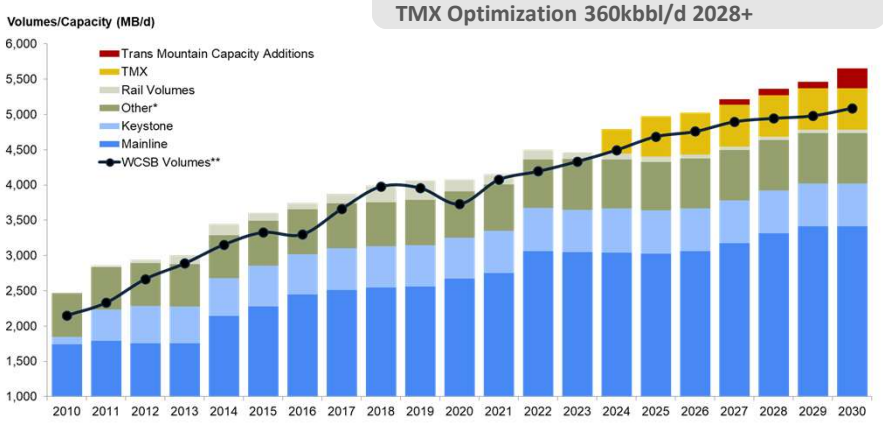
Source: Peters & Co. Research

ATHABASCA BLENDED SALES EXPOSURE



CANADIAN EGRESS OUTLOOK

Incremental Egress Projects
ENB Mainline Optimization 400kbbl/d 2027+
TMX Optimization 360kbbl/d 2028+



Source: Peters & Co. Research – WCSB Oil Supply Update and New Pipeline Proposals Advancing (Nov 28, 2025)
*Other includes Express, Rangeland and Trans Mountain pipelines
**Volumes presented net of domestic WCSB refinery demand

See reader advisory "Oil and Gas Information" and "Non-GAAP and other Financial Measures and Production Disclosure" for more information.
Alberta blended sales exposure includes Corner Phase 1 production forecast.

THERMAL OIL – ASSET OVERVIEW

THERMAL OIL DIVISION
PREDICTABLE, LOW DECLINE

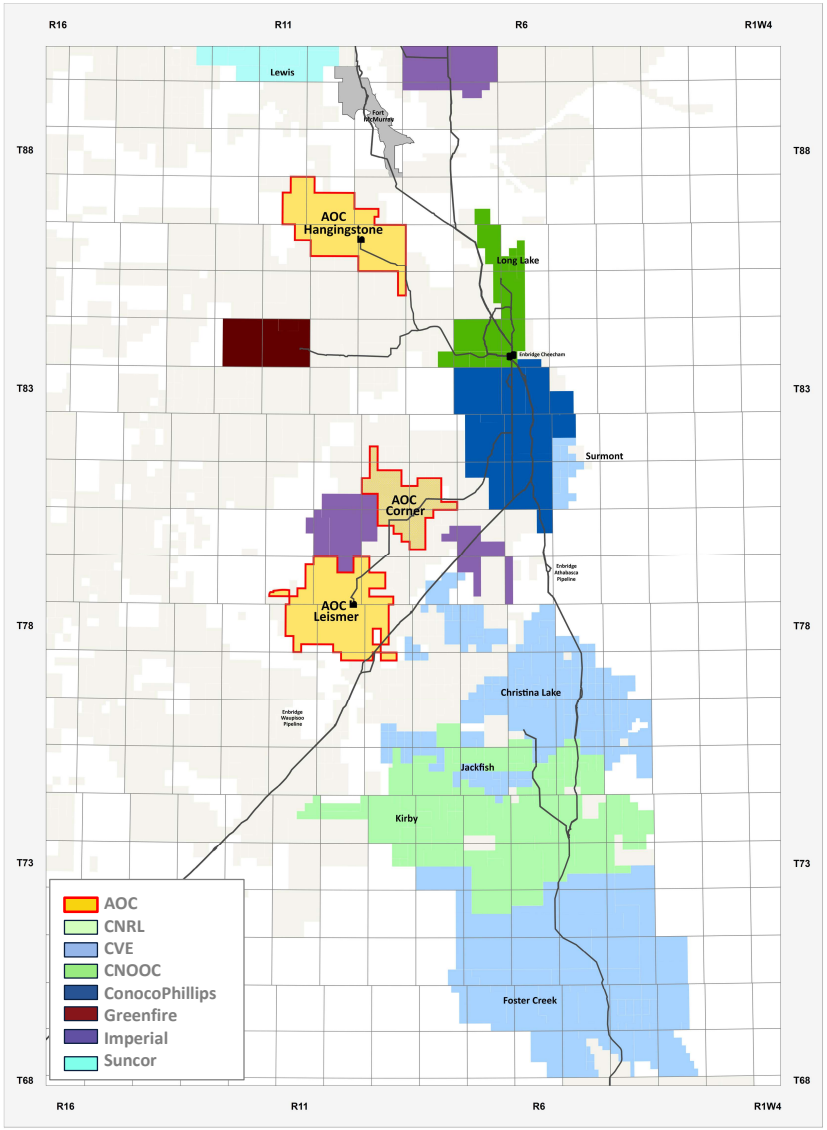
ATHABASCA OIL CORPORATION

HIGHLIGHTS

32,000 – 34,000 bbl/d	2026e Average *(incl. turnarounds)*
~48,000 bbl/d	2027e Exit Rate
$273MM	2026e Capital Expenditures
~US$55 WTI	5-year Growth Capital Break-even (incl. Corner)
~$8/bbl	Sustaining Capital (5-year average)
392MMbbl	1P Reserves
1,201MMbbl	2P Reserves
1,020MMbbl	2C Resource (Best Est.)

	2P (MMbbl)	2C (MMbbl)	Future Rate (bbl/d)	2P RLI Future (years)	2P + 2C RLI Future (years)
Hangingstone	161	36	~8,500	~50	~65
Leismer	687	464	~40,000	~50	~80
Corner	353	520	~40,000	~25	~60
Total	**1,201**	**1,020**	**~88,500**	**~40**	**~70**

THERMAL PROPERTIES (MCMURRAY FAIRWAY)



Consolidated reserves & resources as of December 31, 2025. Contingent Resources Best Estimate. Calculation for Reserve Life Index ("RLI") is 2025 year end reserves divided by future plateau production forecast. Breakeven price reflects sustaining capital and growth capital funded within funds flow. Sustaining Capital is management's assumption of the required capital to maintain the Company's production base (incl. sustaining well pairs, pump changes and maintenance). See reader advisory "Oil and Gas Information" and "Non-GAAP and other Financial Measures and Production Disclosure" for more information.

LEISMER – BROWNFIELD GROWTH

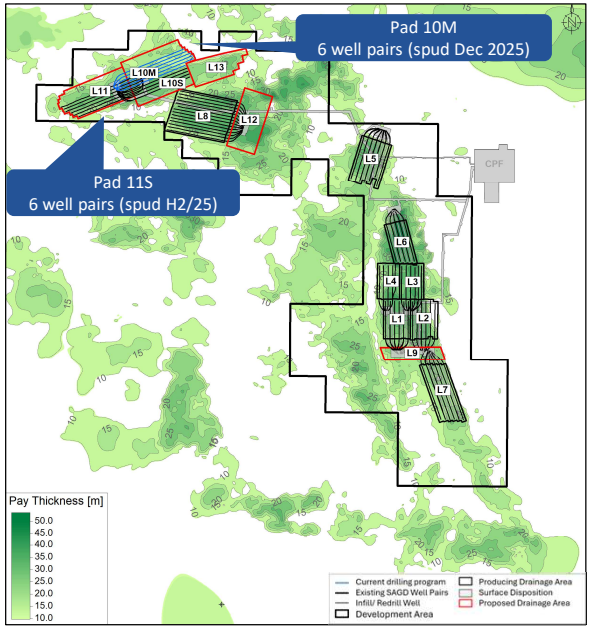
TOP TIER OIL SANDS PROJECT

- Current production ~27,000 bbl/d (February)
- Long reserve life
  - 687MMbbl 2P reserves; 464MMbbl Best Est. Contingent Resource
  - ~50 year 2P RLI at 40,000 bbl/d
- High quality reservoir underpins low corporate decline
  - New wells have flat production profile for 5 – 7 years
  - ~3x long-term steam oil ratio
- 2025 Operating Netback of ~$42/bbl
  - Low pre-payout Crown royalties of ~5% until late 2028 (US$65 WTI)

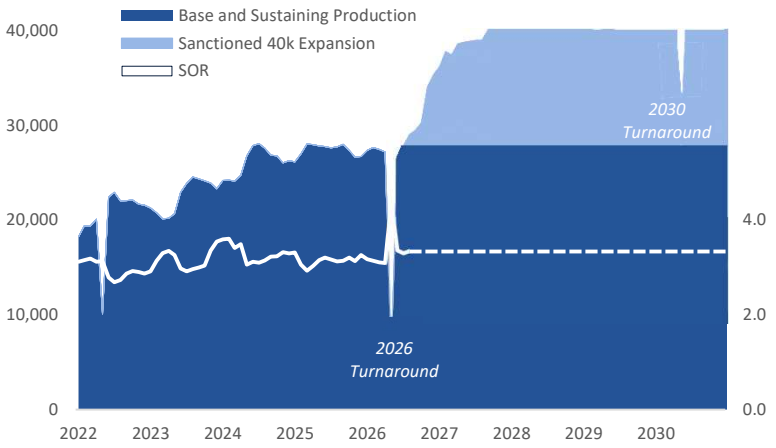
2026 ACTIVITY (~$240MM CAPITAL)

- 12 well pair drilling campaign completed in March
  - Steaming to commence in a staged sequence following the turnaround
- Three-week facility turnaround in May (~$20MM)
  - Includes tie-in points for the expansion project
- Progressive growth
  - ~31,000-32,000 bbl/d 2026 exit
  - ~40,000 bbl/d 2027 exit

DEVELOPMENT MAP



LEISMER DEVELOPMENT (BBL/D)



Reserves and resources as of December 31, 2025. Calculation for Reserve Life Index ("RLI") is 2025 year end 2P reserves divided by production of ~28,000 bbl/d
See reader advisory "Oil and Gas Information" and "Non-GAAP and other Financial Measures and Production Disclosure" for more information.

LEISMER – 40,000 BBL/D PROGRESSIVE EXPANSION

SANCTION JULY 2024

Project Cost	~$300MM
Incremental Rate	12,000 bbl/d
Capital Efficiency	~$25,000/bbl

McDaniel 2P NPV10 $3.3 billion[1]

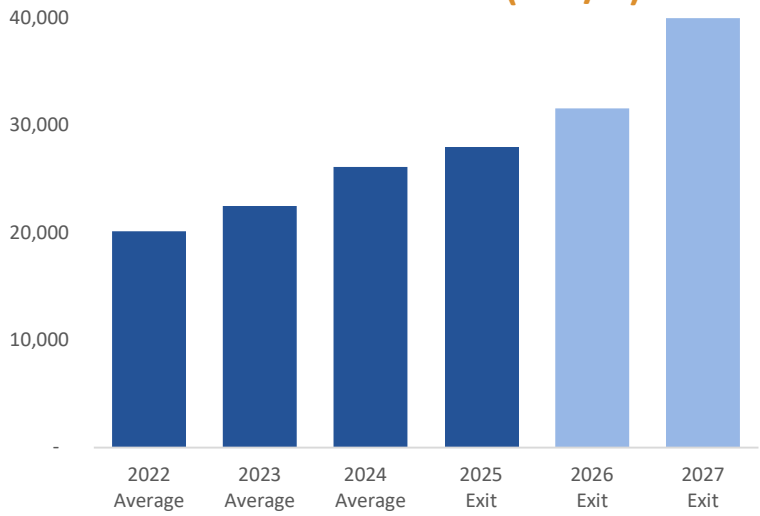
COMPLETED

- ✓ Regulatory approval 40,000 bbl/d
- ✓ Established transportation to Edmonton
- ✓ Long-lead steam generators acquired counter-cyclically
- ✓ Landed major equipment including steam generators, heat exchangers and vessels

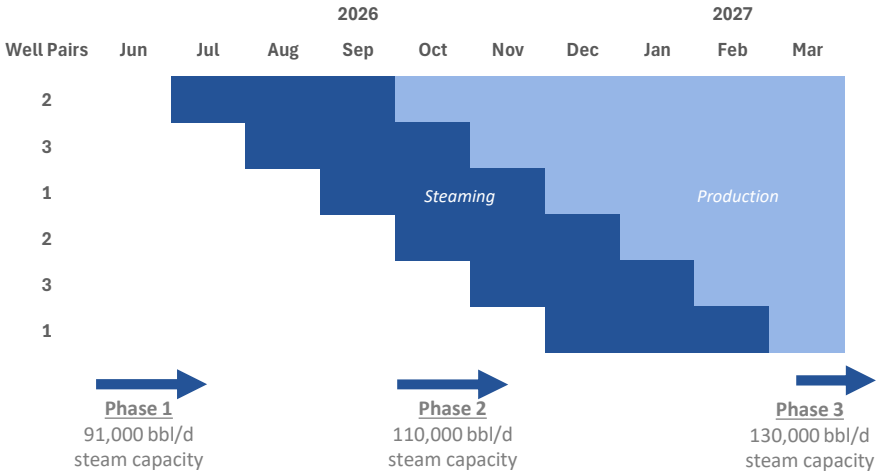
SCOPE

- Facility capacity expansion
  - ~130,000 bbl/d steam generation
  - 40,000 bbl/d bitumen processing
- ~$300MM capital (substantially complete by year-end 2026)
  - ~$190MM CPF capital
  - ~$110MM well pair capital

HISTORICAL PRODUCTION & GROWTH OUTLOOK (BBL/D)



EXPANSION PRODUCTION SCHEDULE



[1] McDaniel & Associate Consultants 2025 year-end reserves evaluation.
See reader advisory "Oil and Gas Information" and "Non-GAAP and other Financial Measures and Production Disclosure" for more information.

HANGINGSTONE – CASH FLOW GENERATION

PROJECT HIGHLIGHTS

- Current production ~9,000 bbl/d (February)
- Long reserve life; ~50 year Reserve Life Index
  - 161MMbbl 2P reserves; $787MM McDaniels 2P NPV10
- Stable SOR at 3.4x with field-wide NCG co-injection

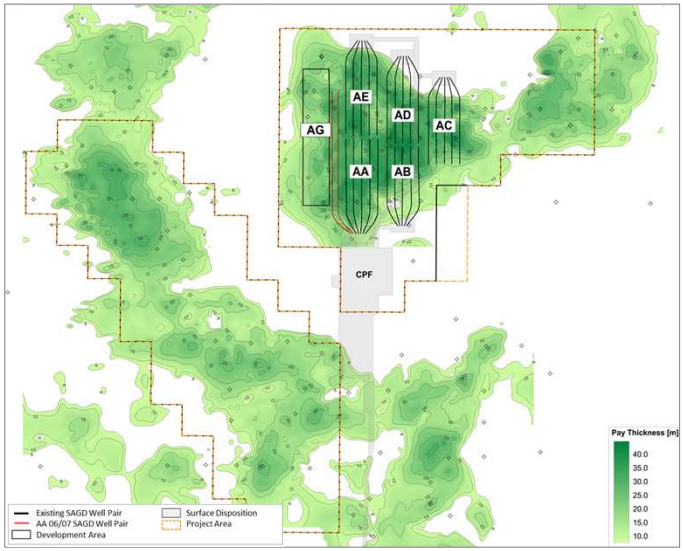
2026 ACTIVITY (~$17MM CAPITAL)

- Two-week facility turnaround in April (~$5MM)
- Readiness activities for future sustaining pads

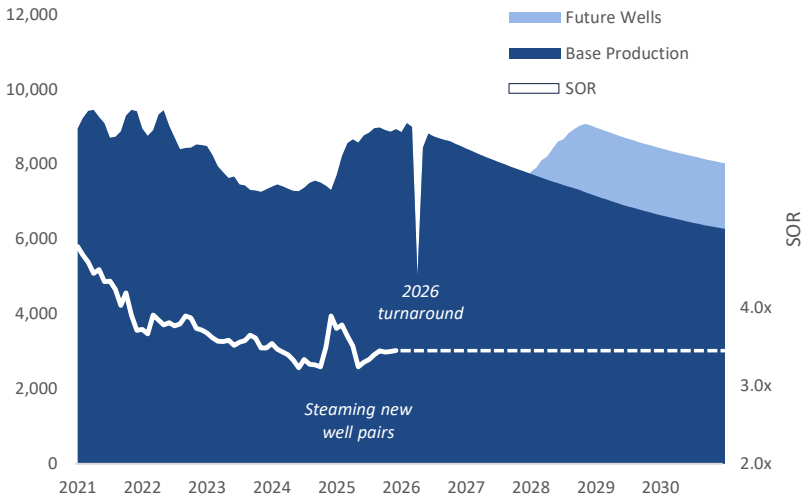
CASH GENERATION

- ~$300MM Operating Income over the last three years
- 2025 Operating Netback of ~$35/bbl
  - Low pre-payout Crown royalties of ~5% beyond 2030 (US$65 WTI)

DEVELOPMENT MAP



HANGINGSTONE DEVELOPMENT (BBL/D)



Reserves and resources as of December 31, 2025. Calculation for Reserve Life Index ("RLI") is 2025 year end reserves divided by production of ~8,500 bbl/d.
See reader advisory "Oil and Gas Information" and "Non-GAAP and other Financial Measures and Production Disclosure" for more information.

CORNER – NEXT FUNDED GROWTH PROJECT

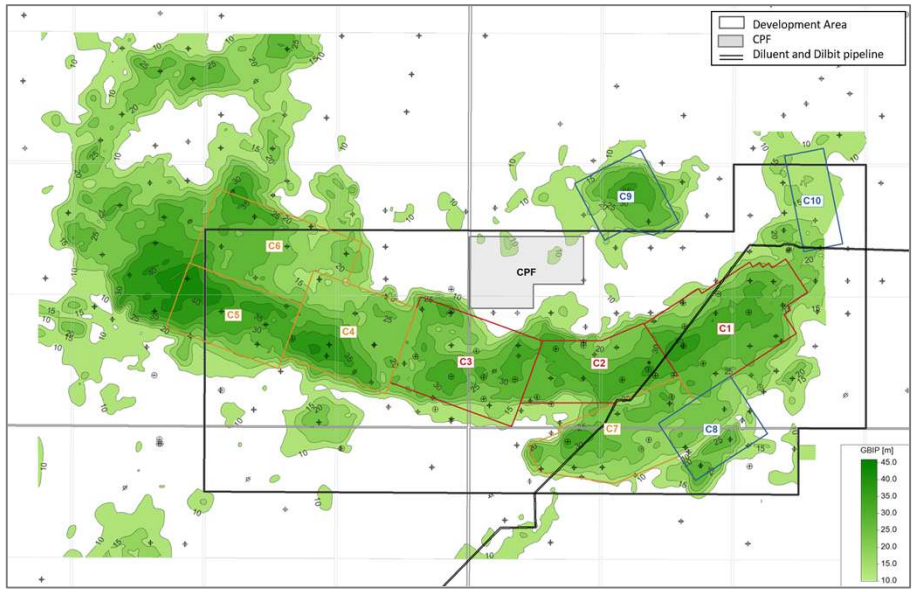
TOP TIER OIL SANDS PROJECT

- Large de-risked asset
  - Regulatory approval for 40,000 bbl/d
  - 353MMbbl 2P & 520MMbbl Contingent Resource (Best Est.)
  - 304 delineation wells with ~80% 3D seismic coverage
- Located in the heart of the McMurray In Situ fairway
  - Adjacent to Leismer with shared area infrastructure
  - High quality reservoir; anticipate iSOR of <3.0x

PRE-SANCTION ACTIVITY

- 2026 activity of ~$16MM
  - CPF, road and pad-site preparation this winter
  - Finalized cost estimates and advancing lump-sum execution structures to enhance certainty over project cost and schedule
- Planning modular design for progressive growth
  - 15,000 bbl/d projects with ~3 year timeline to first oil
- Competitive economics for full project
  - ~$30,000 - $35,000/bbl/d capital efficiency
- Self-funded growth
  - Planned sanction in H2 2026, investment decision contingent on a favorable macro environment

DEVELOPMENT MAP



ANALOGOUS REGIONAL MCMURRAY RESERVOIR PROPERTIES[1]

Properties	Corner	Leismer	CVE Foster Creek	CVE Christina Lake	MEG Christina Lake	CNRL Jackfish
Depth (m TVD)	**497**	445	500	325-400	359	400-459
GBIP Thickness (m)	**Up to 45 Avg. 21**	Up to 40 Avg. 25	Up to 30	Up to 45	24	17.6
GBIP Oil Saturation (%)	**84**	81	85	80	60-85	75
GBIP Effective Porosity (%)	**35**	34	34	31	30-36	34
GBIP Hz Perm (D)	**6.1**	5.4	Up to 10	Up to 10	5	Up to 5.4

Reserves and resources as of December 31, 2025.
[1] External reservoir properties taken from 2023 AER D54 presentations.

DUVERNAY ENERGY CORPORATION

ATHABASCA
OIL CORPORATION

DUVERNAY ENERGY – CORPORATE SNAPSHOT

SUBSIDIARY COMPANY – ATHABASCA OPERATED

- Unparalleled exposure to Kaybob Duvernay oil window
- ~200,000 acres; ~432 well locations
- Operatorship of strategic infrastructure
- Strong balance sheet with $48MM of Liquidity

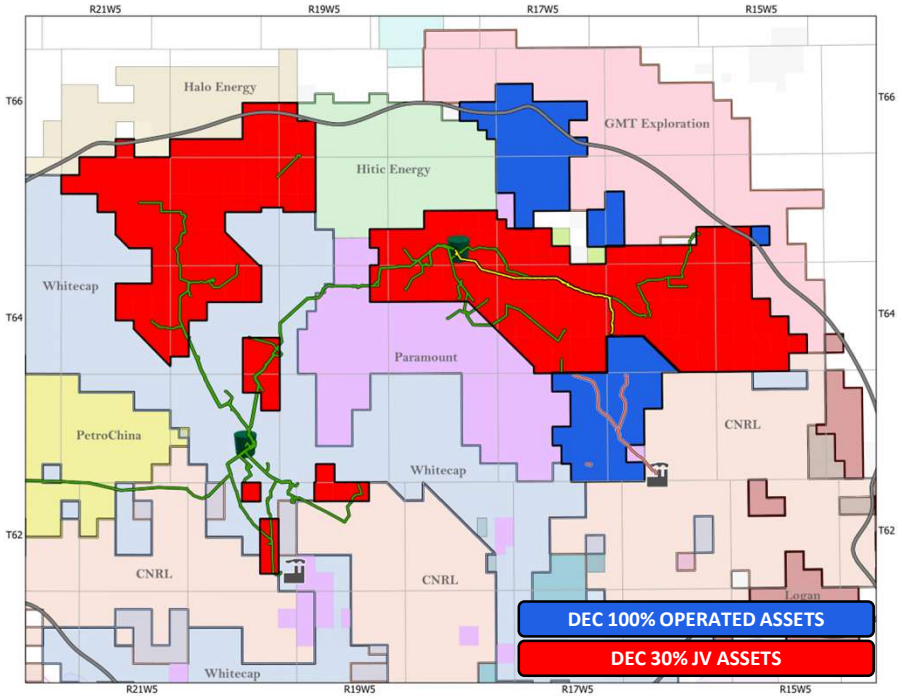
LONG-TERM ACTIVITY

- Development plans funded within cash flow and balance sheet
- Impactful activity on 100% WI acreage, augmented by JV activity

VALUE PROPOSITION

- Self-funded development within DEC with growth to >15,000 boe/d (75% Liquids) by 2030
- Value crystallization expected as material scale is reached

KAYBOB DUVERNAY LAND MAP



2026 OUTLOOK

Equity Ownership	70% AOC / 30% CVE
2026e Production (gross)	~5,000 boe/d ~35% annual growth
2026e Capital (gross)	$38MM

See reader advisory "Oil and Gas Information" and "Non-GAAP and other Financial Measures and Production Disclosure" for more information. ~200,000 gross acres comprised of ~46,000 acres 100% working interest and ~155,000 acres 30% working interest.

DUVERNAY ENERGY – DEVELOPMENT PLANS

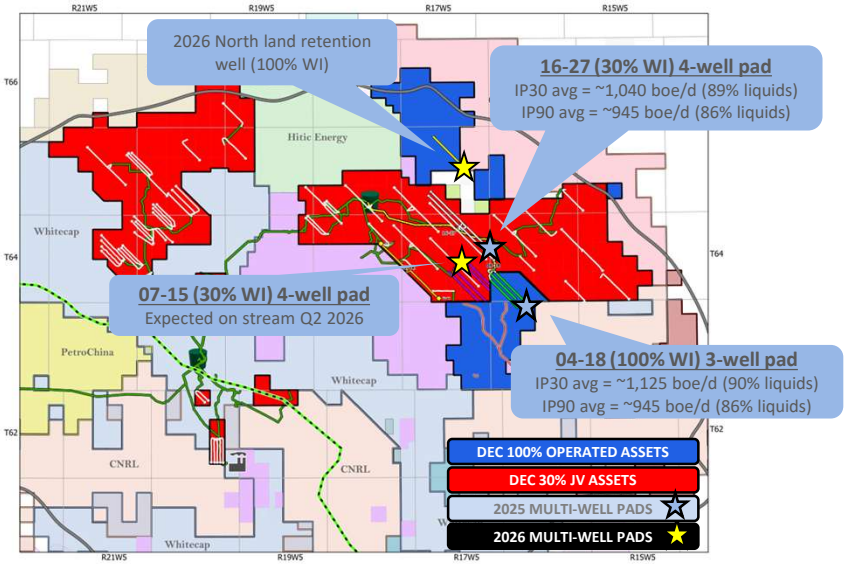
2025 HIGHLIGHTS

- Strong initial well results >1,000 boe/d (~90% liquids)
- Competitive liquids rich netbacks (~$35/boe 2025)
  - Primarily condensate; low operating costs, no encumbrances (GORRs)

2026 ACTIVITY ($38MM CAPITAL)

- North land retention well (100% WI)
- Multi-well pad on-stream Q2 2026 (30% WI)
- Flexibility to accelerate operated activity in supportive macro conditions

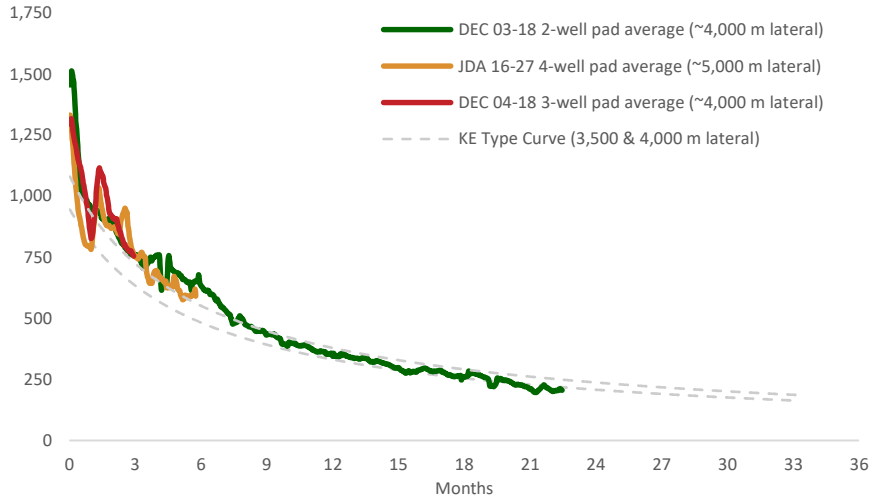
KAYBOB DUVERNAY LAND MAP


2026 North land retention well (100% WI)
16-27 (30% WI) 4-well pad
IP30 avg = ~1,040 boe/d (89% liquids)
IP90 avg = ~945 boe/d (86% liquids)
07-15 (30% WI) 4-well pad
Expected on stream Q2 2026
04-18 (100% WI) 3-well pad
IP30 avg = ~1,125 boe/d (90% liquids)
IP90 avg = ~945 boe/d (86% liquids)
DEC 100% OPERATED ASSETS
DEC 30% JV ASSETS
2025 MULTI-WELL PADS
2026 MULTI-WELL PADS
Hitic Energy
Whitecap
PetroChina
CNRL

KAYBOB EAST ILLUSTRATIVE ECONOMICS 4,000M LATERAL & 1,500 LB/FT (US$65 WTI)

		2-WELL PAD	4+ MULTI WELL PAD
Capital (DCET) per well	*$MM*	$14	$10
IP365 per well	*boe/d*	593	593
EUR	*Mboe*	904	904
Liquids Yield	*%*	77%	77%
IRR	*%*	51%	107%
Recycle Ratio	*x*	3.4x	4.8x
P/I	*x*	0.8x	1.4x
Payout	*months*	18	10

KAYBOB ILLUSTRATIVE TYPE CURVE (BOE/D)



See reader advisory "Oil and Gas Information" and "Non-GAAP and other Financial Measures and Production Disclosure" for more information.

Flat long term commodity prices for Illustrative Type Curve Economics (US$65 WTI, C$3 AECO, 0.725 C$/US$ FX).

APPENDIX

2026 BUDGET & OUTLOOK

2026 OUTLOOK (US$65 WTI, US$12.50 DIFF)

	Thermal Oil	Duvernay Energy (100%)*	**Consolidated**
Production *(inclusive of ~2,500 boe/d turnaround impacts)*	32,000 – 34,000 bbl/d	~5,000 boe/d	**37,000 – 39,000 boe/d** **Exit ~43,000 boe/d**
Adj. Funds Flow			**~$425 – $450MM**
Capital *(incl. $25MM turnaround)*	$273MM	$38MM	**~$310MM**

THERMAL OIL BUDGET HIGHLIGHTS

- Progressing Leismer expansion
  - Capital spend substantially complete by year-end
  - Ramp up to ~40,000 bbl/d in 2027
- Corner Phase 1 preparation
  - Planned sanction in 2026, investment decision contingent on a favorable macro environment
- Return of Capital Framework
  - Maintain 100% Free Cash Flow to share buybacks
- Balance sheet strength provides flexibility
  - Managing multi-year capital projects
  - Augment share buybacks beyond Free Cash Flow

DUVERNAY ENERGY BUDGET HIGHLIGHTS

- Positioning for future growth
  - North land retention well (100% WI)
  - Multi-well pad on-stream Q2 2026 (30% WI)
  - Readiness activity for future development pads
- Flexibility for accelerated activity with favorable macro environment
- Continued self-funded growth strategy
  - ~35% annual production growth

2026 pricing: US$65 WTI, US$12.50 WCS diff, C$3 AECO, 0.725 C$/US$ FX. 2026 production: 90% Bitumen, 2% natural gas (comprised of 99%+ of shale gas), 7% Condensate NGLs, 1% Other NGLs.
*DEC capital funded independently through its funds flow and its balance sheet. See reader advisory "Oil and Gas Information" and "Non-GAAP and other Financial Measures and Production Disclosure" for more information.

CAPITALIZATION & HEDGING

LONG-TERM DEBT

- C$200MM 2029 Unsecured Notes
  - Issued August 2024; 5-year term to 2029
  - 6.75% coupon

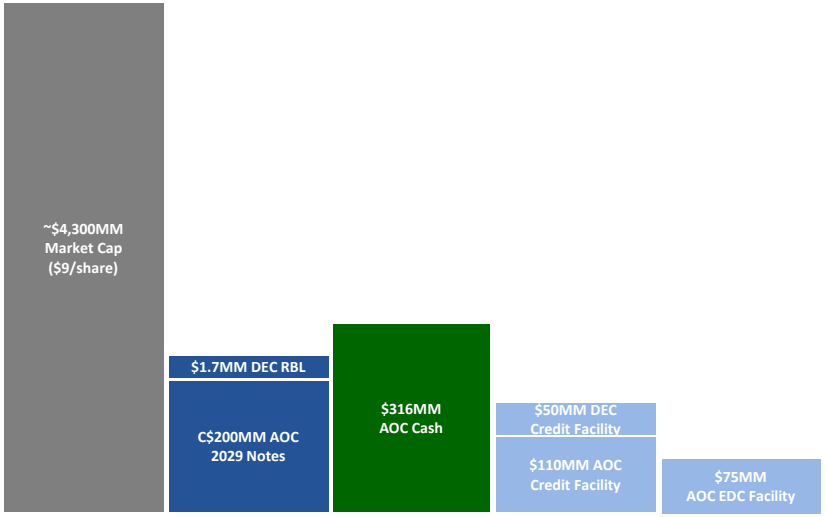
STRONG LIQUIDITY

- AOC Liquidity of ~$395MM, including $316MM cash
- DEC Liquidity of ~$48MM
- Facilities utilized for transportation LCs & hedging capacity

EXCELLENT EXPOSURE TO COMMODITY UPSIDE

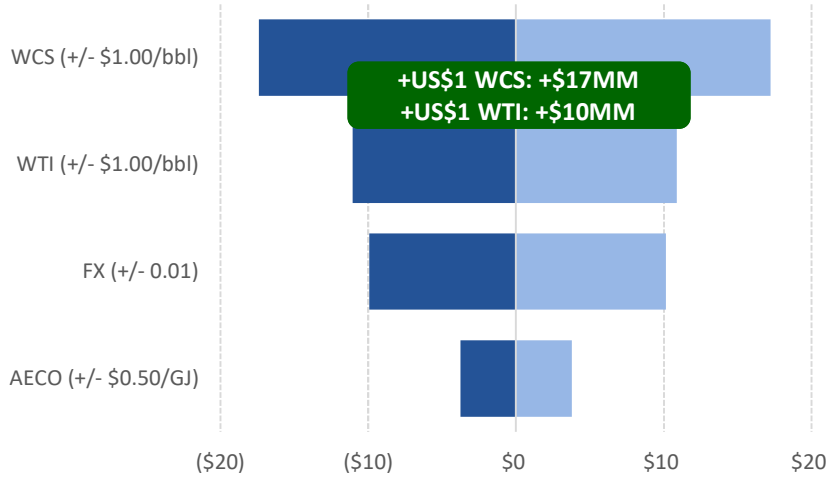
- Strong Liquidity and low Sustaining Capital provides protection against price volatility
- AOC 2026 Thermal Oil hedges:
  - WCS diff Q1 2026: 2,000 bbl/d at US$12.50/bbl
  - C5+ diff input cost: 3,000 bbl/d at US$1.83/bbl
  - Gas input cost: 25,000 GJ/d at C$2.78/GJ

CONSOLIDATED CAPITAL STRUCTURE



Note: not to scale

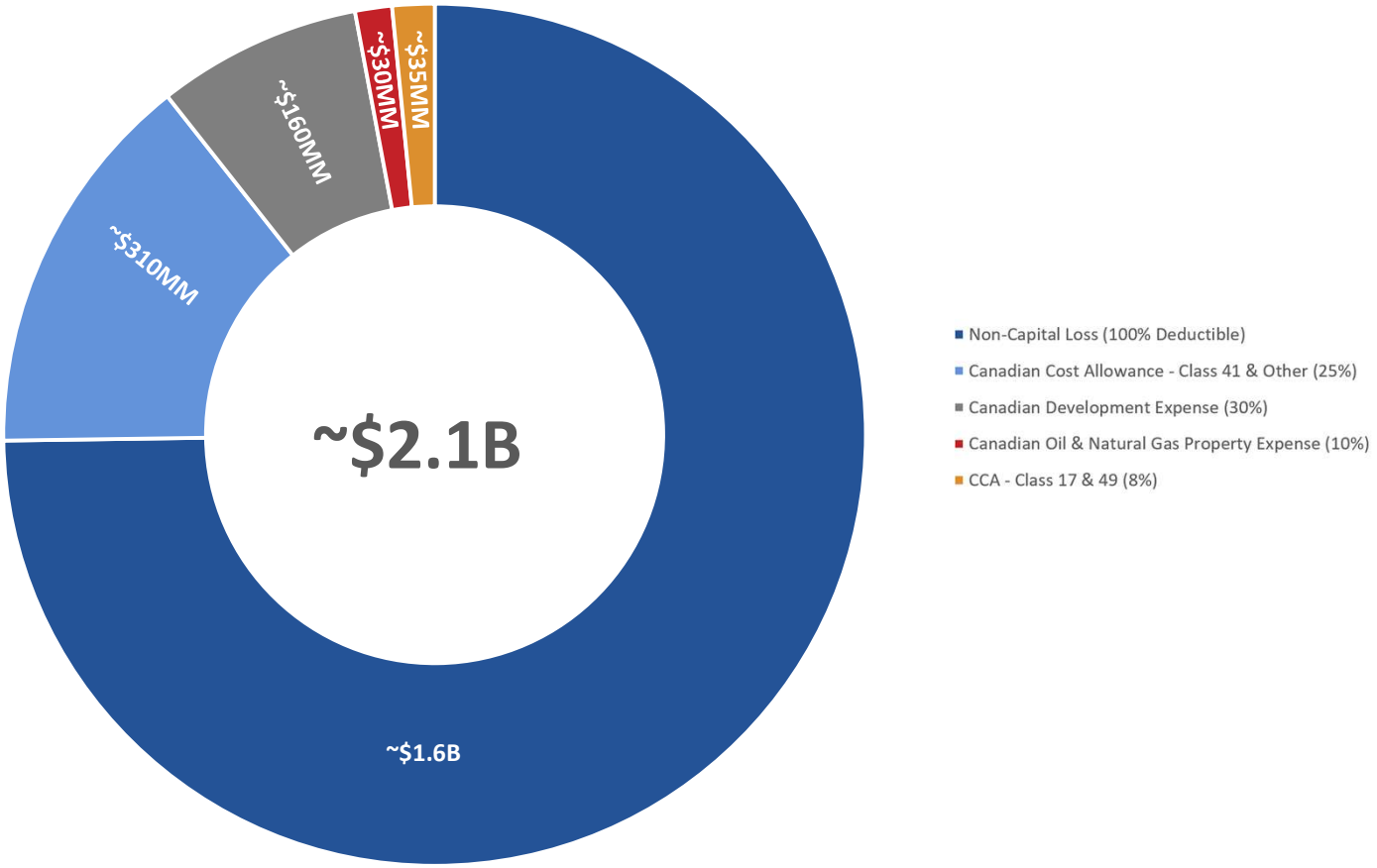
2026 ADJ. FUNDS FLOW SENSITIVITY ($MM)



Capitalization as at December 31, 2025. Illustrative sensitivity reflects full year funds flow impact for changes in each variable.
See reader advisory "Oil and Gas Information" and "Non-GAAP and other Financial Measures and Production Disclosure" for more information.

VALUABLE TAX POOLS

TAX POOL SUMMARY (Q4 2025)



THERMAL OIL – CROWN ROYALTY ADVANTAGE

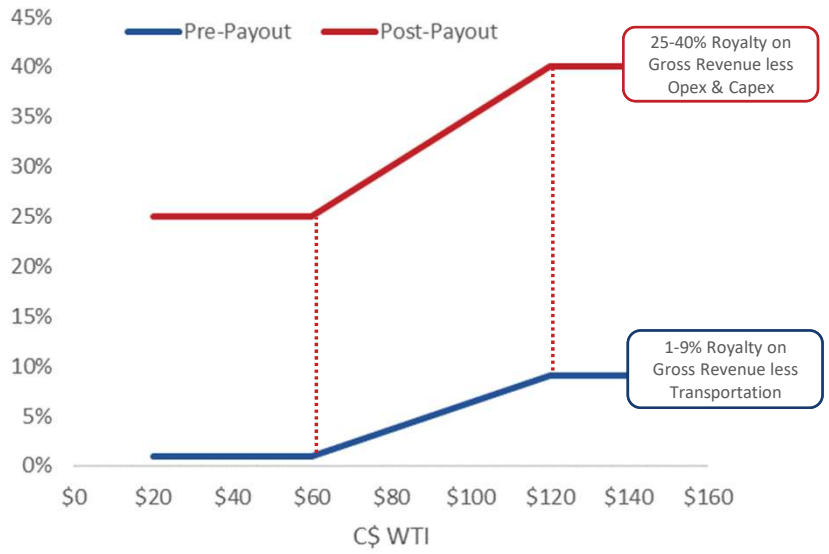
CROWN ROYALTY OVERVIEW

- Royalty structure depends on whether a project is in pre-payout or post-payout phase
- Pre-payout advantage designed to support the recovery of the initial investment

ATHABASCA ADVANTAGE (US$65 WTI)[1]

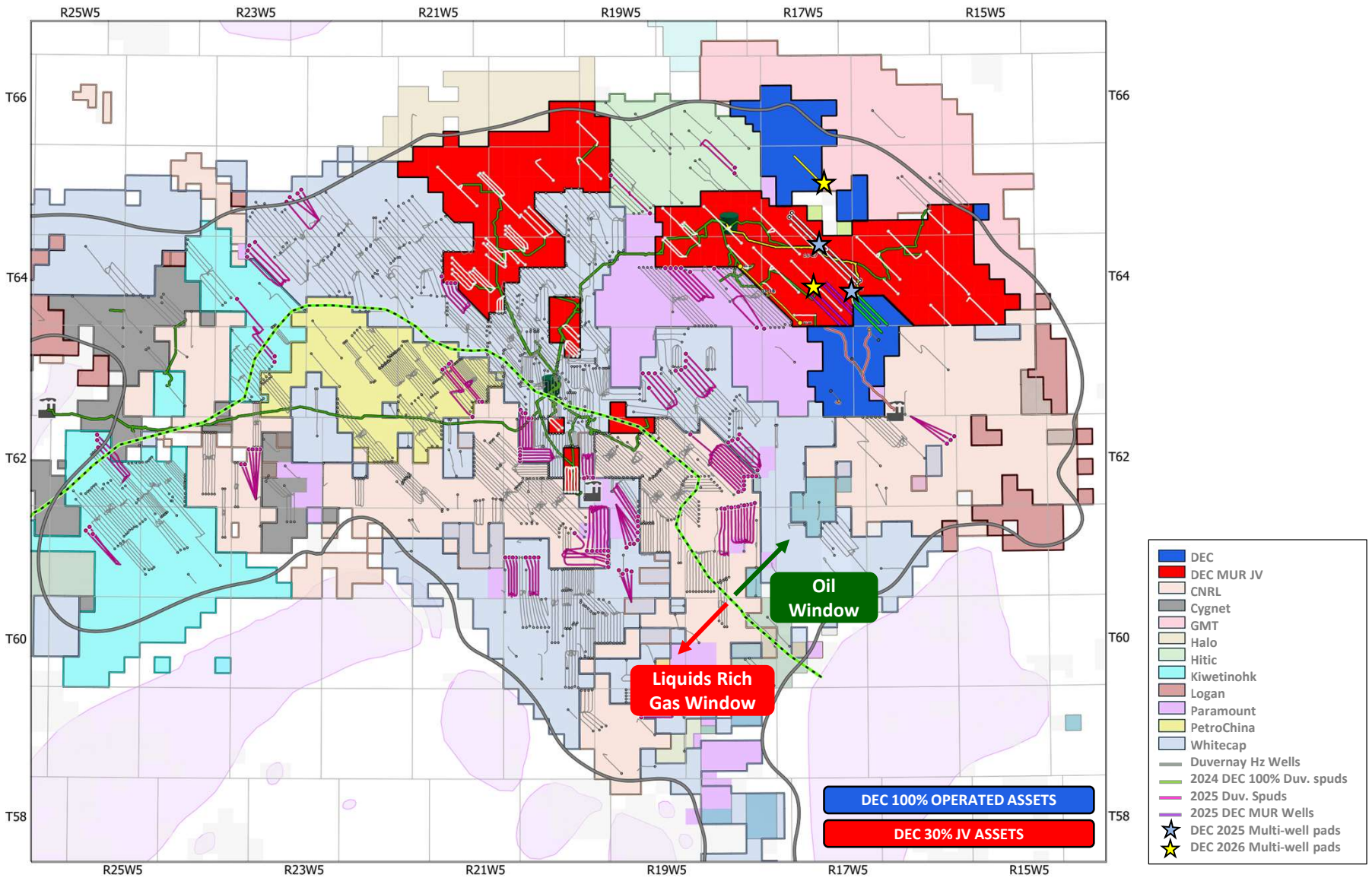
- Leismer to remain in pre-payout to late 2028
- Hangingstone to remain in pre-payout until 2030+

OIL SANDS ROYALTY RATES



[1]2026+ pricing: US$65 WTI, US$12.50 WCS diff, C$3 AECO, 0.725 C$/US$ FX.

DUVERNAY ENERGY – KAYBOB ACTIVITY MAP

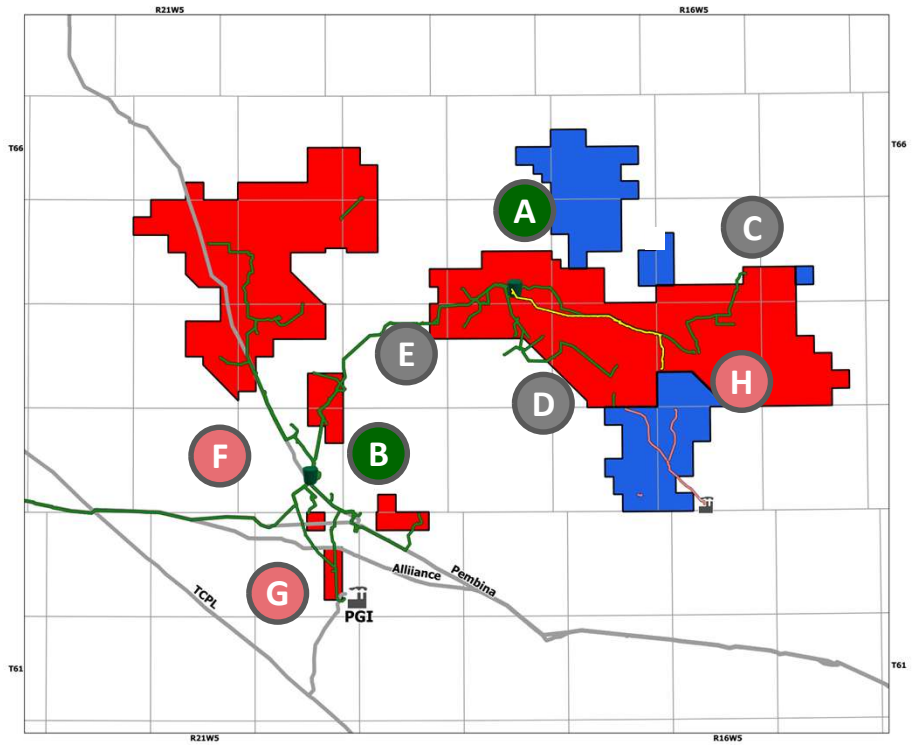


DUVERNAY ENERGY – INFRASTRUCTURE

INFRASTRUCTURE ADVANTAGE

- Significant owned and operated infrastructure
- Facility enlargements in progress at Kaybob West
- Oil infrastructure directly connected to the Pembina Peace liquids system
- Gas infrastructure dually connected to Pembina Gas Infrastructure KA Facility and Keyera Simonette Facility

DUVERNAY ENERGY INFRASTRUCTURE OVERVIEW



- **A** Kaybob East Oil Battery
  24 mmcf/d & 11,000 bbl/d
- **B** Kaybob West Oil Battery
  132 mmcf/d & 22,500 bbl/d (June 2026)
- **C** Two Creeks Gathering Line
- **D** Kaybob East Gathering Line
- **E** Kaybob East / West Interconnect
- **F** Keyera Simonette Gas Interconnect
- **G** Pembina Gas Infrastructure Gas Interconnect
- **H** DEC Gathering Lines to existing infrastructure

MANAGEMENT TEAM

	Rob Broen, P.Eng. *President & Chief Executive Officer*	○ President and Chief Executive Officer since 2015; 13 years at Athabasca ○ Over 30 years of exploration and production experience including 18 years with Talisman Energy with roles as President, Talisman Energy USA Inc. and Senior Vice President, North American Shale. ○ BSc. in Chemical Engineering from the University of Alberta and graduate of Ivey Executive Program
	Matt Taylor, CFA *Chief Financial Officer*	○ Chief Financial Officer since 2019; 11 years at Athabasca ○ 20 years of financial, corporate and capital markets experience including equity research and investment banking at National Bank Financial, GMP Securities and CIBC World Markets ○ BCom in Finance from UBC Sauder School of Business and Chartered Financial Analyst designation
	Karla Ingoldsby, P.Eng. *Vice President, Thermal Development and Operations*	○ Vice President, Thermal Development and Operations since 2018; 15 years at Athabasca ○ Over 20 years of Oil and Gas experience, including reservoir engineering roles at Royal Dutch Shell overseeing thermal oil assets and conventional oil and gas assets ○ BSc. in Mechanical Engineering from the University of Alberta
	Paul Vander Valk, P.Eng., MBA *Vice President, Projects & Well Delivery*	○ Vice President, Projects & Well Delivery since 2025; 3 years at Athabasca ○ 30 years of oil and gas industry experience; previously COO for Harvest and Vice President, Production Systems at Cenovus Energy ○ BSc. in Civil Engineering from the University of Calgary and MBA from Heriot-Watt University
	Bruce Beynon, P. Geol, MSc. *Vice President, Light Oil*	○ Joined Athabasca in December 2023 as Vice President, Light Oil ○ Over 30 years of oil and gas industry experience included roles of Executive Vice President, Exploration and Corporate Development at Baytex Energy Corporation and President of Raging River Exploration ○ Professional geologist with a Bachelors and Master of Science degrees in Geology from the University of Alberta
	Cam Danyluk, LLB, BCom *VP Business Development & General Counsel*	○ VP Business Development & General Counsel since joining Athabasca in 2022 ○ Over 20 years of legal, business development, and investment banking experience; previously VP, Legal, General Counsel and Corporate Secretary at Total Energy Services ○ LLB and BCom in Finance from the University of Alberta

READER ADVISORY

Forward Looking Statements

This Presentation contains forward-looking information that involves various risks, uncertainties and other factors. Within this Reader Advisory and Forward Looking Statements, references to the "Company" means Athabasca and Duvernay Energy, as and where applicable. All information other than statements of historical fact is forward-looking information. The use of any of the words "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "target", "forecast", "goal", "aspiration", "commit", "believe", "should", "could", "intend", "may", "potential", "outlook" and similar expressions suggesting future outcome are intended to identify forward-looking information. The forward-looking information is not historical fact, but rather is based on the Company's current plans, objectives, goals, strategies, estimates, assumptions and projections about the Company's industry, business and future operating and financial results. This information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. No assurance can be given that these expectations will prove to be correct and such forward-looking information included in this Presentation should not be unduly relied upon. This information speaks only as of the date of this Presentation. In particular, this Presentation contains forward-looking information pertaining to, but not limited to, the following: our strategic plans; growth in production; future debt levels and repayment plans; the allocation of future capital; return of capital strategy including timing and quantum of share buybacks; our drilling plans; our growth plans; capital efficiencies; ramp-up to expected production rates at our assets and improved margins with scale; timing of Leismer and Hangingstone's pre-payout royalty status; applicability of tax pools; exemption from U.S. tariffs; Net Cash positions; Adjusted Funds Flow, Operating Income, Cash Flow and Free Cash Flow over various periods; the impact of future hedge levels; type well and project economic metrics; number of drilling locations; forecasted daily production and the composition of production; break-even metrics, market access, sustaining capital metrics and other matters.

In addition, information and statements in this Presentation relating to "Reserves" and "Resources" are deemed to be forward-looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and that the reserves and resources described can be profitably produced in the future. With respect to forward-looking information contained in this Presentation, assumptions have been made regarding, among other things: commodity prices; the regulatory framework governing royalties, taxes and environmental matters in the jurisdictions in which the Company conducts and will conduct business and the effects that such regulatory framework will have on the Company, including on the Company's financial condition and results of operations; the Company's financial and operational flexibility; the Company's financial sustainability; the Company's cash flow break-even commodity prices; the Company's ability to obtain qualified staff and equipment in a timely and cost-efficient manner; the applicability of technologies for the recovery and production of the Company's reserves and resources; future capital expenditures to be made by the Company; future sources of funding for the Company's capital programs; the Company's future debt levels; future production levels; the Company's ability to obtain financing and/or enter into joint venture arrangements, on acceptable terms; operating costs; compliance of counterparties with the terms of contractual arrangements; impact of increasing competition globally; collection risk of outstanding accounts receivable from third parties; geological and engineering estimates in respect of the Company's reserves and resources; recoverability of reserves and resources; the geography of the areas in which the Company is conducting exploration and development activities and the quality of its assets. Certain other assumptions related to the Company's Reserves and Resources are contained in the report of McDaniel & Associates Consultants Ltd. ("McDaniel") evaluating Athabasca's Proved Reserves, Probable Reserves and Contingent Resources as at December 31, 2025 (which is respectively referred to herein as the "McDaniel Report").

Actual results could differ materially from those anticipated in this forward-looking information as a result of the risk factors set forth in the Company's Annual Information Form ("AIF") dated March 4, 2026 available on SEDAR at www.sedarplus.ca, including, but not limited to: weakness in the oil and gas industry; exploration, development and production risks; prices, markets and marketing; market conditions; trade relations and tariffs; climate change and carbon pricing risk; statutes and regulations regarding the environment including deceptive marketing practices; regulatory environment and changes in applicable law; gathering and processing facilities, pipeline systems and rail; reputation and public perception of the oil and gas sector; environment, social and governance goals; political uncertainty; state of capital markets; ability to finance capital requirements; access to capital and insurance; abandonment and reclamation costs; changing demand for oil and natural gas products; anticipated benefits of acquisitions and dispositions; royalty regimes; foreign exchange rates and interest rates; reserves; hedging; operational dependence; operating costs; project risks; supply chain disruption; financial assurances; diluent supply; third party credit risk; indigenous claims; reliance on key personnel and operators; income tax; cybersecurity; advanced technologies; hydraulic fracturing; liability management; seasonality and weather conditions; unexpected events; internal controls; evolving corporate governance, sustainability and reporting framework; limitations of insurance; litigation; natural gas overlying bitumen resources; competition; chain of title and expiration of licenses and leases; breaches of confidentiality; new industry related activities or new geographical areas; water use restrictions and/or limited access to water; relationship with Duvernay Energy Corporation; management estimates and assumptions; third-party claims; conflicts of interest; inflation and cost management; credit ratings; growth management; impact of pandemics; ability of investors resident in the United States to enforce civil remedies in Canada; and risks related to our debt and securities. All subsequent forward-looking information, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Also included in this Presentation are estimates of the Company's 2026-30 outlook which are based on the various assumptions as to production levels, commodity prices, currency exchange rates and other assumptions. To the extent any such estimate constitutes a financial outlook, it was approved by management and the Board of Directors of Athabasca and is included to provide readers with an understanding of the Company's outlook. Management does not have firm commitments for all of the costs, expenditures, prices or other financial assumptions used to prepare the financial outlook or assurance that such operating results will be achieved and, accordingly, the complete financial effects of all of those costs, expenditures, prices and operating results are not objectively determinable. The actual results of operations of the Company and the resulting financial results may vary from the amounts set forth herein, and such variations may be material. The outlook and forward-looking information contained in this Presentation was made as of the date of this Presentation and the Company disclaims any intention or obligations to update or revise such outlook and/or forward-looking information, whether as a result of new information, future events or otherwise, unless required pursuant to applicable law.

Oil and Gas Information

"BOEs" may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent (6 Mcf: 1 bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Other Oil and Gas terms: This presentation contains certain other oil and gas metrics, including D&C (drilling and completion costs), F&D, steam oil ratio (or SOR), reserves life index, recycle ratio, capital efficiency and P/I, which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included herein to provide readers with additional measures to evaluate the Company's performance; however, such measures are not reliable indicators of the future performance and future performance may not compare to the performance in previous periods and therefore such metrics should not be unduly relied upon.

D&C includes all capital spent to drill, complete, equip and tie-in a well. The calculation of F&D costs includes all exploration and development capital for the year plus the change in future development capital for the year. Steam oil ratio, or SOR, measures the average volume of steam required to produce a barrel of oil. Capital efficiency is a measure of how effective projects are at adding production. Lower capital efficiencies indicate a more productive investment for adding production. For Light Oil and Duvernay Energy capital efficiency is calculated by dividing Capital and IP365 rates and for Thermal Oil is calculated by dividing Capital and plateau rates. All Thermal Oil production and volumes are bitumen. Light Oil and Duvernay Energy % liquids include oil, condensate and NGLs as liquids. Consolidated % liquids include bitumen, oil, condensate and NGLs as liquids. Natural Gas volumes include both Conventional and Shale Gas, however most gas volumes are Shale Gas. Sustaining capital is a management estimate of annual capital projects required to maintain production levels.

READER ADVISORY CONT'D

Initial Production Rates

Test Results and Initial Production Rates: The well test results and initial production rates provided herein should be considered to be preliminary, except as otherwise indicated. Test results and initial production rates disclosed herein may not necessarily be indicative of long-term performance or of ultimate recovery.

Reserves Information

The McDaniel Report was prepared using the assumptions and methodology guidelines outlined in the COGE Handbook and in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities, effective December 31, 2025. There are numerous uncertainties inherent in estimating quantities of bitumen, light crude oil and medium crude oil, tight oil, conventional natural gas, shale gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth above are estimates only. In general, estimates of economically recoverable reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially. For those reasons, estimates of the economically recoverable reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. Reserves figures described herein have been rounded to the nearest MMbbl or MMboe. For additional information regarding the consolidated reserves and information concerning the resources of the Company as evaluated by McDaniel in the McDaniel Report, please refer to the Company's AIF.

Reserve Values (i.e. Net Asset Value) is calculated using the estimated net present value of all future net revenue from our reserves, before income taxes discounted at 10%, as estimated by McDaniel effective December 31, 2025 and based on average pricing of McDaniel, Sproule and GLJ as of January 1, 2026.

Well Inventory

The 432 gross Duvernay drilling locations referenced include: 95 proved undeveloped locations and 88 probable undeveloped locations for a total of 183 booked locations with the balance being unbooked locations. Proved undeveloped locations and probable undeveloped locations are booked and derived from the Company's most recent independent reserves evaluation as prepared by McDaniel as of December 31, 2025 and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal management estimates. Unbooked locations do not have attributed reserves or resources (including contingent or prospective). Unbooked locations have been identified by management as an estimation of Athabasca's multi-year drilling activities expected to occur over the next two decades based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, commodity prices, provincial fiscal and royalty policies, costs, actual drilling results, additional reservoir information that is obtained and other factors.

Non-GAAP and other Financial Measures and Production Disclosure

The "Corporate Consolidated Adjusted Funds Flow", "Corporate Consolidated Adjusted Funds Flow per Share", "Athabasca (Thermal Oil) Adjusted Funds Flow", "Duvernay Energy Adjusted Funds Flow", "Corporate Consolidated Free Cash Flow", "Athabasca (Thermal Oil) Free Cash Flow", "Duvernay Energy Free Cash Flow", "Corporate Consolidated Operating Income", "Corporate Consolidated Operating Income Net of Realized Hedging", "Athabasca (Thermal Oil) Operating Income", "Duvernay Energy Operating Income", "Corporate Consolidated Operating Netback", "Corporate Consolidated Operating Netback Net of Realized Hedging", "Athabasca (Thermal Oil) Operating Netback", "Duvernay Energy Operating Netback" and "Cash Transportation and Marketing Expense" financial measures contained in this Presentation do not have standardized meanings which are prescribed by IFRS and they are considered to be non-GAAP financial measures or ratios. These measures may not be comparable to similar measures presented by other issuers and should not be considered in isolation with measures that are prepared in accordance with IFRS. Sustaining Capital, Net Cash and Liquidity are supplementary financial measures. The Leismer and Hangingstone operating results are supplementary financial measures that when aggregated, combine to the Athabasca (Thermal Oil) segment results.

Adjusted Funds Flow and Free Cash Flow are non-GAAP financial measures and are not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS. The Adjusted Funds Flow and Free Cash Flow measures allow management and others to evaluate the Company's ability to fund its capital programs and meet its ongoing financial obligations using cash flow internally generated from ongoing operating related activities. Adjusted Funds Flow per share is a non-GAAP financial ratio calculated as Adjusted Funds Flow divided by the applicable number of weighted average shares outstanding.

The non-GAAP measure Duvernay Energy Operating Income is calculated by subtracting the Duvernay Energy Segments royalties, operating expenses and transportation & marketing expenses from petroleum and natural gas sales which is the most directly comparable GAAP measure. The Duvernay Energy Operating Netback per boe is a non-GAAP financial ratio calculated by dividing the Duvernay Energy Operating Income by the Duvernay Energy production. The Duvernay Energy Operating Income and the Duvernay Energy Operating Netback measures allow management and others to evaluate the production results from the Company's Duvernay Energy assets.

The non-GAAP measure Athabasca (Thermal Oil) Operating Income is calculated by subtracting the Athabasca (Thermal Oil) segments cost of diluent blending, royalties, operating expenses and cash transportation & marketing expenses from heavy oil (blended bitumen) and midstream sales which is the most directly comparable GAAP measure. The Athabasca (Thermal Oil) Operating Netback per boe is a non-GAAP financial ratio calculated by dividing the respective projects Operating Income by its respective bitumen sales volumes. The Athabasca (Thermal Oil) Operating Income and the Athabasca (Thermal Oil) Operating Netback measures allow management and others to evaluate the production results from the Company's Athabasca (Thermal Oil) assets.

(1) Duvernay Energy and Corporate Consolidated reflect gross financial metrics before taking into consideration Athabasca's 70% equity interest in Duvernay Energy.

READER ADVISORY CONT'D

Sustaining Capital is management's assumption of the required capital to maintain the Company's production base.

Net Cash is defined as the face value of long-term debt, plus accounts payable and accrued liabilities, plus current portion of provisions and other liabilities plus income tax payable less current assets, excluding risk management contracts.

Liquidity is defined as cash and cash equivalents plus available credit capacity.

Recycle ratio is calculated by dividing estimated project operating netbacks by finding and development costs per boe.

Profit-to-Investment Ratio is a measure of a projects net value relative to its capital investment and is calculated by dividing a project's NPV10 value by its Capital.

Reserve Life Index is calculated by dividing 2025 year-end reserves with Q4 2025 production, unless otherwise stated.

Break Even is an operating metric that calculates the US$WTI oil price required to fund operating costs (Operating Break-even), sustaining capital (Sustaining Break-even), or growth capital (Total Capital) within Adjusted Funds Flow.

Enterprise Value to Debt Adjusted Cash Flow is a valuation metric calculated by dividing Enterprise Value (Market Capitalization plus Net Debt) divided by Cash Flow before interest costs.

Production

Athabasca (Thermal Oil) 2026 forecasted total average daily production is 32,000 – 34,000 bbl/d. Athabasca expects that 100% of that production will be comprised of bitumen. Duvernay Energy's forecasted total daily average production of ~5,000 boe/d for 2026 is expected to be comprised of approximately 69% tight oil, 22% shale gas and 9% NGLs.

Liquids is defined as bitumen, tight oil, light crude oil, medium crude oil and natural gas liquids.

Historical annual year-end Corporate volumes by product are provided below:

Product		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Bitumen	*bbl/d*	7,384	27,900	27,900	26,058	22,745	26,805	28,989	30,246	33,505	35,905
Natural Gas	*mcf/d*	13,858	20,890	33,104	28,281	23,229	20,506	16,169	10,769	4,677	4,947
Condensate NGLs	*bbl/d*	788	2,687	2,793	2,009	1,964	1,374	962	528	-	-
Other NGLs	*bbl/d*	383	505	1,049	918	785	856	730	525	329	311
Light & Medium Crude Oil	*bbl/d*	331	104	98	27	2	20	30	31	40	40
Tight Oil	*bbl/d*	784	758	1,823	2,471	3,116	2,145	1,856	1,364	2,162	2,294
Total	***boe/d***	**11,980**	**35,435**	**39,180**	**36,196**	**32,483**	**34,618**	**35,262**	**34,490**	**36,815**	**39,375**

Initial Production Rates

Test Results and Initial Production Rates: The well test results and initial production rates provided in this presentation should be considered to be preliminary, except as otherwise indicated. Test results and initial production rates disclosed herein may not necessarily be indicative of long-term performance or of ultimate recovery